BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

---------In the Matter of--------)) PUBLIC UTILITIES COMMISSION)) Instituting a Proceeding to) Investigate Implementing a) Decoupling Mechanism for Hawaiian) Electric Company, Inc., Hawaii) Electric Light Company, Inc., and) Maui Electric Company, Limited.))	DOCKET NO. 2008-0274

THE DEPARTMENT OF BUSINESS, ECONOMIC DEVELOPMENT, AND TOURISM'S RESPONSES TO THE PUBLIC UTILITIES COMMISSION'S POST HEARING INFORMATION REQUESTS

AND

CERTIFICATE OF SERVICE

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The Department of Business, Economic Development, and Tourism ("Department" or "DBEDT"), through the undersigned Deputy Attorney General, hereby submits to the Hawaii Public Utilities Commission ("Commission" or "PUC"), its responses to the Commission's post hearing information requests ("IRs") submitted to the Parties in the above-referenced docket on July 15, 2009. The PUC directed the HECO Companies to respond to the first six IRs within fourteen days from date of issue (i.e., July 29, 2009), and also directed all Parties to respond to the remaining IRs within twenty-eight days from date of issue (i.e., August 12, 2009). On July 31, 2009, the HECO Companies filed a request to the Commission for an extension of time for filing their responses to the first six IRs to August 7, 2009, and for all the Parties to file their responses to the remaining IRs on August 24, 2009. On August 7, 2009, the Commission approved HECO's requests for extension of time for filing responses to the PUC's post hearing IRs.

Following are DBEDT's responses to PUC-POST-HEARING-IR-7 through PUC-POST-HEARING-IR-14.

PUC-POST-HEARING-IR-7

Please discuss the success and failures of decoupling in other jurisdictions (e.g., Maine).

PUC-POST-HEARING-IR-7-DBEDT-RESPONSE:

The following discusses and summarizes the decoupling mechanism implemented in Maine, Idaho, Oregon, Washington, New York, California, and Maryland. Maine's decoupling mechanism was generally considered a failure and therefore it does not have a current decoupling program. One state (California) has had and continues to have a successful decoupling program. The remaining states (Idaho, Oregon, New York, and Maryland) have current decoupling programs (mostly pilot programs) with no significant issues or problems.

Maine:

Maine first implemented a revenue decoupling pilot program for Central Maine Power (CMP) in 1991 to promote energy efficiency and conservation. The program was referred to as Electric Revenue Adjustment Mechanism (ERAM), which provided for an annual adjustment to the allowed revenues based on changes in the utility's number of customers (the mechanism was also referred to as "ERAM per customer") capped at one percent. The plan was not a multi-year plan, and the utility was free to file a rate case at any time to adjust the allowed revenues. The program was applicable to residential and commercial customers, and was planned as a 3-year pilot program but was terminated three months early, ending on November 30, 1993.

The program was terminated earlier than planned due to the significant rate increases resulting from several factors, the most significant of which was the economic recession ongoing at the time decoupling was implemented. Around the time of program inception, New England was experiencing serious economic recession, resulting in lower sales levels, which in turn caused substantial revenue deferrals that the utility was ultimately entitled to recover. By the end of 1992, the ERAM revenue deferral had reached $52 million, only a small portion of which was viewed as resulting from the utility's conservation programs, and a major portion of which was due to the impact of the economic recession. Thus, the decoupling program was increasingly viewed as a mechanism shielding the utility from the impact of the recession rather than a mechanism to promote energy efficiency and conservation.[1] Additionally, the situation was exacerbated by an unexpected decision by the Securities and Exchange Commission that changed the financial accounting rules, limiting the amount of time that utilities could carry deferrals on their books to two years, resulting in a rate increase for

[1] Report on Revenue Decoupling for Transmission & Distribution Utilities Presented to the Utilities & Energy Committee by the MPUC, OPA and OEIS. January 31, 2008.

customers ranging from 6 to 8 percent within the two year period.[2]

In addition to the decoupling program, there were other factors which increased rates for CMP's customers, including fuel and seasonal rate adjustments and a rate design change which allocated more of the utility's fixed costs to the residential class. These factors, combined with decoupling, resulted in 50-60 percent rate increases for some residential customers.[3]

In 2007, Maine initiated a new attempt to mandate electric decoupling. This attempt died in the legislature.

Idaho:

In March 2007, the Idaho PUC approved a three-year decoupling pilot program for Idaho Power Company, the state's largest electric company. The mechanism is a Fixed Cost Adjustment (FCA) mechanism based on an RPC for residential and small commercial customers, designed to recover the utility's fixed costs independent from the kilowatt-hour sales. The fixed costs portion of the company's revenue requirements for these two rate classes was determined in a general rate case, and thereafter the FCA adjusted rates to recover the difference

[2] "Decoupling in a Downturn", Chad Garrett. Energy Pulse. www.energypulse.net
[3] Ibid.

between the fixed costs actually recovered in rates and the authorized fixed costs in the company's most recent rate case.

Idaho Power's decoupling mechanism was implemented on a pilot basis for a three-year period beginning January 1, 2007 through December 31, 2009. The first rate adjustment occurred in June 1, 2008, and subsequent rate adjustments were to occur on June 1 of each year during the pilot term, coincident with Idaho Power's Power Cost Adjustment (PCA). The Company was to file its FCA adjustment request on March 15th of each year.[4]

Sales are adjusted for weather and the annual cumulative rate increases are capped at 3%. The Company also agreed to provide with its March 15th filing a detailed summary of energy efficiency and demand-side management (DSM) activities that demonstrate an enhanced commitment resulting from the implementation of the FCA mechanism and removal of the financial disincentive to energy efficiency and DSM.[5]

The pilot program continues and the overall effectiveness of the program has yet to be evaluated. Initial results are mixed. In the first year of the program, average energy use increased per residential customer and decreased for the small business customers, which resulted in an overcollection.[6] The

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[4] Idaho Public Utilities Commission. Case No. IPC-E-04-15, Order No. 30267, March 12, 2007.

[5] Ibid.

[6] "Electric Rate Decoupling in Other States", Kevin E. McCarthy, OLR Research Report, 2009-R-0026, January 21, 2009.

Commission recommended refunding the overcollection in cents per kWh to both customer classes.

Oregon:

The Public Utilities Commission of Oregon (OPUC) approved an alternative form of regulation plan (AFOR) for the distribution function of Pacificorp's retail electric utility service beginning in 1998 through 2001, which included several measures to encourage energy efficiency and conservation. The distribution-only AFOR included a revenue cap designed to help de-link the utility's profit from kilowatt-hour sales. The plan based rate changes on a general measure of inflation adjusted by a productivity index. Any rate increases under the plan was capped at two percent per year and to a total cap of five percent over the term of the plan, and because of the productivity offset, the increase will always be less than the general rate of inflation. Under the mechanism, the weather-adjusted actual sales revenues of each customer class were compared to a predetermined revenue cap for that class, and any differences would be collected in a balancing account for recovery the following year. The plan also included revenue sharing between customers and PacifiCorp for all earnings outside a predetermined earnings range; and a non-bypassable system benefits charge and renewable resources incentive to encourage investment in sustainable energy resources and to allow the utility to recover other energy efficiency investments.[7] A review of this mechanism indicates that the rate impacts have been minimal (estimated at less than 1% for 1999 to 2001); that energy efficiency activity has increased and budget levels doubled from pre-AFOR levels.[8]

In Order No. 09-020 issued on January 22, 2009, the OPUC approved Portland General Electric Company's (PGE) decoupling mechanism based on the fixed cost recovery true-up mechanism, which included a Sales Normalization Adjustment balancing account (SNA) applied to residential and small non-residential customers, and a Lost Revenue Recovery (LRR) applied to large commercial and industrial customers with loads less than one megawatt. In Order No. 09-176, UE 197, dated May 19, 2009, the OPUC clarified the conditions set out in the initial approving order including: (1) the recovery under the decoupling mechanism is allocated by the respective customer class' contribution to the decoupling adjustment balance; (2) the length of the program is two years; (3) PGE's authorized Return on Equity (ROE) is reduced by 10 basis points to reflect the reduction in the Company's risk (and PGE should file an application to defer the revenue requirement effect of this change until it can be

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[7] 183 PUR4th 39-71.

[8] "Breaking the Consumption Habit-Ratemaking for Efficient Resources Decisions, Sheryl Carter. NRDC. 12/1/2004.

reflected in base rates); and (4) the two percent "soft cap", which would cause amounts in excess of two percent to be transferred to interest-bearing deferred accounts to be recovered in rates after the two-year decoupling mechanism has expired, was modified to an absolute limit or "hard cap" on PGE's fixed-cost recovery, such that any amount remaining in the deferred account after application of the two percent rate cap in the second year of the decoupling will not be eligible for recovery.[9] This mechanism just started and the results are yet to be determined.

In September 2002, the Oregon Public Utility Commission approved a pilot decoupling program for NW Natural Gas. A decoupling mechanism for Cascade Natural Gas was implemented in April 2006. Both natural gas decoupling mechanisms are still ongoing.

NW Natural Gas' decoupling mechanism is applicable to residential and commercial customers and is based on a revenue per customer mechanism, reconciling actual margin per customer with rate-making margin per customer and with adjustments for changes in number of customers by class. The mechanism also adjusts for changes in consumption attributable to annual changes in commodity cost or periodic changes in the company's

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[9] OPUC. UE 197, Order No. 09-176, May 19, 2009.

general rates.[10] Weather adjustments are not covered by the adjustment. Additional revenues or credits produced by the mechanism are booked to a deferral account and reconciled as part of the company's annual purchased gas adjustment.[11]

Cascade Natural Gas' decoupling mechanism has service quality requirements which include penalties for failing to perform below specified ratios on customer complaints.[12] The program includes a percent public purpose surcharge and percent of revenue contribution for customers to fund conservation programs. Cascade's program is scheduled to remain in effect until September 2010. An independent evaluation is also planned for the program.

Washington:

In May 1990, the Washington Utilities and Transportation Commission ("WUTC") issued a Notice of Inquiry (NOI) which requested comments on four general objectives to be served by programs or mechanisms that encourage the goals of least-cost planning. Those objectives included adjustment for changes in revenues and costs beyond a utility's control; purchased power cost recovery; conservation cost recovery; and incentives for least-cost supply and demand acquisition.[13]

[10] Natural Gas Rate Round-Up, Natural Gas Association, "Update on Revenue Decoupling Mechanisms". April 2007.
[11] Ibid.
[12] Ibid.
[13] 137 PUR 4th 377-393.

In October 1990, Puget Sound Power and Light Company (Puget Sound) filed its proposed periodic revenue adjustment mechanism (PRAM) which involved decoupling revenues from kilowatt-hour sales, and was adopted by the WUTC on an experimental basis. The utility's proposal was to file for rate adjustment annually, and a general rate case filing every three years. In May 1991, Puget Sound filed its requested rate adjustment of $39.1 million under PRAM (generally referred to as PRAM 1) for the period October 1, 1991 to September 30, 1992. On September 25, 1991, the WUTC granted a rate increase of $38.1 million.[14]

On June 1, 1992, Puget Sound filed for an additional revenue increase of $92.2 million for the period October 1, 1992 to September 30, 1993 (PRAM 2). After hearing and reviewing oral and documentary evidence, the WUTC authorized the utility to refile tariff revisions to reflect a rate increase of $66,360,449 for PRAM 2, and the tariffs must include a termination date of September 30, 1993.[15]

In its Eleventh Supplemental Order issued on September 21, 1993, the WUTC found that "PRAM has achieved its primary goal – the removal of disincentives to conservation investments," and extended PRAM for another three years.[16]

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[14] Ibid.
[15] Ibid.
[16] "Breaking the Consumption Habit-Ratemaking for Efficient Resource Decision", Sheryl Carter. NRDC. 12/1/2004.

In recent years, decoupling has been revisited for natural gas companies. The Avista pilot program began on February 1, 2007 to promote energy efficiency and conservation and is scheduled to expire on October 31, 2010. The program is only applicable to residential and small commercial customers.

Under its decoupling program, Avista cannot earn more than its authorized rate of return and any recovery of margin differences is based on achieving specific conservation targets related to demand side management savings.[17] The pilot also has an adjustment for new customer usage. Any new customer usage added since the corresponding month of the test year is subtracted from the total current month usage.[18] Avista's mechanism limits annual rate increases due to decoupling to 2% annually. In addition, Avista is required to retain a third party to audit the result of DSM savings and an evaluation is required prior to filing a program extension.

New York:

New York has implemented decoupling mechanisms in both the electric and natural gas industries. The mechanisms were initially implemented for several utilities in the early 1990s, including the Orange and Rockland Utilities, Inc., Consolidated Edison of New York, Inc., and Niagara Mohawk Power Corporation.

[17] Docket UG-060518, Order 04, pgs. 4-5.
[18] Ibid.

The intent was to promote energy efficiency and distributed generation.[19] The decoupling mechanisms were subsequently eliminated in the mid-1990s when New York State's Public Service Commission ("NYPSC") deregulated the electric industry and the New York Energy Research and Development Authority ("NYERDA") was given the primary responsibility for developing and implementing conservation programs.[20]

The concerns of the decoupling structure at that time were large accruals, customer bill volatility, distorted price signals, and reduced economic development incentives.[21] Later evaluations determined that the actual rate impacts of the decoupling mechanisms were minimal, with fluctuations in rates of less than one percent in most years and never greater than four percent.[22]

On April 20, 2007, the NYPSC issued a decoupling order (Case 03-E-0640). In the order, electric and gas utilities are required to develop true-up based revenue decoupling mechanisms for consideration in individual utility rate cases. The recent decoupling mechanisms are to complement New York's "15 x 15 Energy Efficiency" initiative (reduce 2015 electricity sales by

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[19] New York State Department of Public Service, "Revenue Decoupling: New York's Experience & Future Directions", July 17, 2007.
[20] McCarthy, Kevin E., OLR Research Report 2005-R-0702, "Decoupling Utility Sales and Earnings", October 3, 2005 www.cga.ct.gov/2005/rpt/2005-R-0702.htm.
[21] New York State Department of Public Service, "Revenue Decoupling: New York's Experience & Future Directions", July 17, 2007.
[22] NARUC: "Decoupling for Electric & Gas utilities FAQ", September 2007.

15% from currently projected levels).[23] Proposals have been approved for Consolidated Edison and Orange & Rockland utilities. Both proposals are revenue-per-customer mechanisms with annual true-ups.[24]

In September 2007, the NYPSC adopted a three-year gas rate plan for Consolidated Edison of New York, Inc. (Con Edison) which authorized a partial reconciliation of the pure base revenues[25] of the first rate year (RY1) based on a revenue per customer (RPC) revenue adjustment mechanism (RDM). The rate plan initiated a Collaborative, which included several interested parties[26] and was chaired by Con Edison, to evaluate and recommend the design and conditions of the RDM for the next two years (RY2 and RY3). The Collaborative was charged to determine whether an RDM that relies on rate year billing determinants is reasonable and workable, without precluding the

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[23] New York State Department of Public Service, Revenue Decoupling: "New York's Experience & Future Directions", July 17, 2007.
[24] The Edison Foundation, Institute for Electric Efficiency , "Status of Revenue Decoupling for Electric Utilities by State", March 2009
[25] Revenues from delivery rates and charges excluding gross receipt taxes, merchant function charges, billing and payment processing charges, and all other applicable credits or surcharges other than weather normalization adjustment credits or surcharges.
[26] Including Department of Public Service Staff (Staff), New York City, the County of Westchester, New York State Consumer Protection Board, Consumer Power Advocates, New York Energy Consumers Council Inc. (NYECC), Pace Energy Project, NRDC, Public Utility Law Project Inc., Intelligent Energy, National Grid USA Service Co., New York State Electric & Gas Corp, and Rochester Gas & Electric Corp.

evaluation of other alternatives, including the continuation of the RPC mechanism for RY1 with or without modification.[27]

The Collaborative made a diligent effort but was unsuccessful in developing a consensus on an RDM for RY2 and RY3. Among the positions and concerns raised by the parties included New York City's position that the RDM permits Con Edison to recover revenues only from new business requiring additional infrastructure and billing and service expenditures; the NYECC's concerns relating to the monthly volatility of the 30-day equivalent bills to define a customer used in the RY1 RDM; and the year-end projected RDM surcharges not being in line with its expectations. The measurement of the number of customers was a concern of the Staff as well as the NRDC. The Collaborative identified the importance of not only counting customers but also verifying the validity of the resulting number through multiple means. In the end, the most important conclusion to be reached from the Collaborative is that the critical element of an RDM based on RPC is the method used to determine the number of customers.[28]

Con Edison's recommendation submitted on August 5, 2007 was either to continue the RY1 RDM without change for RY2 and RY3 or to modify the determination of the number of customers to use

[27] State of New York Public Service Commission, Case-06-G-1332, Order Continuing Revenue Decoupling Mechanism, Issued and Effective May 19, 2009.
[28] Ibid.

Con Edison's Monthly Customer Average Report ("Customer Report"), which is generated at the billing cycle and includes all active and temporary accounts at the end of the billing cycle. Upon review of the RDM report and the parties initial reply and comments, the Commission ordered that the RDM methodology for RY1 continue for RY2 and RY3 using the 30-day Equivalent Bills to determine the number of customers. The results of this program are yet to be determined.

Orange & Rockland's current electric rate decoupling mechanism was approved in Case 07-E-0949. This type of decoupling mechanism reconciles actual, non-weather adjusted revenues with ratemaking revenues (delivery only) per class with the ratemaking revenues adjusted automatically based on a three-year schedule. This mechanism includes all classes except economic development, lighting, and special contracts. Orange and Rockland's program is scheduled to end June 30, 2011.

California:

California's long-standing decoupling policy spans over 30 years, starting in 1978 when it first adopted a decoupling mechanism called Supply Adjustment Mechanism (SAM) for the natural gas industry. The California Public Utilities Commission (CPUC) adopted a similar mechanism called Electric Rate Adjustment Mechanism (ERAM) for the three major California investor owned utilities beginning with PG&E in 1982, followed by SCE in 1983, and SDG&E in 1984. California's decoupling policy was designed to remove the disincentive for utilities to promote energy efficiency and conservation among energy consumers. It was designed to ensure that utilities retained their expected earnings even as energy efficiency and conservation programs reduce sales.

The structure of the initial electric decoupling mechanism was to establish a revenue requirement for each utility and then reconcile actual revenues to the allowed revenues. The ERAM applied to all customer classes and adjusted target revenues based on factors affecting the cost of service beyond the utility's control, such as inflation and weather. In 1990, the CPUC supplemented the ERAM with a system of performance-based financial incentives for utilities to promote even more cost-effective energy savings. California's ERAM ran through 1996 when it was suspended by the CPUC due to the electric industry restructuring.

A Lawrence Berkeley Laboratory (LBL) report on California's ERAM impact concludes that ERAM "has had a negligible effect on rate levels and has, for PG&E, actually reduced rate volatility."[29] It also reports that "the clearing of the ERAM

[29] Sherryl Carter, "Breaking the Consumption Habit, Ratemaking for Efficient Resource Decisions". The Electricity Journal, vol. 14, Issue 10, pp. 66-74 (December 2001)

balances has accounted for only a small proportion of the total change in the revenue requirements between 1983-1993."[30] The report concludes that "the record in California indicates that the risk-shifting accounted for by ERAM is small or nonexistent, and ERAM has contributed far less to rate volatility than have other adjustments to rates, such as the fuel-adjustment clause." In addition, "... ERAM has been accompanied by rate risk reductions to customers and profit risk reductions to utilities."[31]

In 2001, the legislature required the CPUC to resume electric decoupling. Section 739 of the Public Utilities Code was amended to allow for utilities to recover a reasonable amount of revenues. This legislation was the result of the California Energy Crisis and was intended to keep utilities whole.[32] The first post-restructuring decoupling adjustment mechanisms for Pacific Gas and Electric (PG&E) and Southern California Edison occurred at the end of 2004.[33] The structure of the mechanism for both IOUs reconciles actual revenues to the approved revenue requirement with an attrition adjustment that increases revenue requirements in non-rate case years. The revenue requirements are adjusted for customer growth,

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[30] Ibid.
[31] Ibid.
[32] Florida Public Service Commission, "Report to the Legislature on Utility Revenue Decoupling", December 2008
[33] Lesh, Pamela G., "Rate Impacts and Key Design elements of Gas and Electric Utility Decoupling: A comprehensive review", June 2009

productivity, weather, and inflation (subject to a minimum and maximum level) on an annual basis with rate cases every three or four years.[34] Adjustments occur through an annual electric true-up filing. The current revenue decoupling program is combined with performance incentives for meeting or exceeding energy efficiency targets. The mechanism covers fixed costs for transmission and distribution for all of the companies and fixed costs for generation for two of them.[35] The mechanism requires utilities to track the difference between actual and forecasted revenues in the balancing account. Over-collections are refunded to ratepayers while under-collections are recovered from ratepayers. Decoupling is still continuing in California.

Maryland:

In July 2007, the Maryland Public Service Commission issued an order allowing Potomac Power Company (Pepco) and Delmarva Power and Light Company to implement a decoupling mechanism called a Bill Stabilization Adjustment (BSA) for their ratepayers taking standard offer electric service (i.e., customers who have not chosen a competitive supplier), based on RPC. Under the mechanism, the actual revenues per customer for each rate class are compared to the approved revenues per

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[34] The Edison Foundation, Institute for Electric Efficiency , "Status of Revenue Decoupling for Electric Utilities by State", March 2009

[35] Kevin E.McCarthy, OLR Research Report- 2009-R-0026, "Electric Decoupling in Other States", January 31, 2009, http://www.cga.ct.gov/2009/rpt/2009-R-0026.htm.

customer, and the BSA is adjusted up or down to achieve the approved revenues. The adjustment rate cannot fluctuate more than plus or minus 10%. In approving the BSA for Pepco, the Commission stated that the BSA reduced the risks faced by the company and therefore reduced the company's return on equity by 50 basis points (one half percent).[36] Evaluation of the effectiveness of Maryland's decoupling mechanism is not yet available.

[36] "Electric Rate Decoupling in Other States", Kevin E. McCarthy, 2009-R-0026, January 21, 2009.

PUC-POST-HEARING-IR-8

Please discuss the pros and cons of implementing the revenue enhancements discussed at each 3a, b, c, and d of the Commission's post-hearing IRs.

PUC-POST-HEARING-IR-8-DBEDT-RESPONSE:

The PUC-POST-HEARING-IRs 3a, b, c, and d are alternative inter-rate case revenue adjustment mechanisms to the HECO/CA RAM proposal. Each of these alternative inter-rate case adjustment mechanisms would allow the HECO Companies timely recovery of only specific costs and/or investments incurred such as those relating to "system reliability", "customer additions", "O&M associated with complying with Act 155", or "O&M portion of the RAM proposed by the HECO Companies."

DBEDT believes that the positive attributes of these mechanisms generally include the following:

1. All four inter-rate case adjustment mechanisms provide higher levels of ratepayer safeguards as they include adjustments of only specific items, thereby limiting the rate impact of decoupling relative to the RAM mechanism (full decoupling) proposed by HECO, which encompasses the total O&M costs and plant additions without Commission review.
2. The revenue enhancing mechanisms provided in IRs 3a and 3b allow for recovery of the allowed return on net additions to HECO's plant investments related to system

reliability that have been <u>placed in service</u> including depreciation, and at the same time provide for prudent review and oversight by the Commission. This will likely minimize the potential for rate volatility due to decoupling by eliminating or minimizing the need to true-up significant amounts of plant costs that could result from HECO's proposed rate base adjustment mechanism included in its RAM proposal. These mechanisms are also consistent with the "used and useful" concept for plant costs recovery currently used in Hawaii's regulatory framework.

3. The inter-rate case adjustment mechanism provided in IR 3c, allowing <u>timely</u> recovery of HECO's O&M costs associated with achieving the State energy goals established in Act 155, will hopefully remove the barriers to the utility to promote the increased use and development of renewable energy-based generation.
4. The revenue enhancing mechanism provided in IR 3d, allowing the recovery of the increases in the HECO Companies' total O&M (labor and non-labor) as proposed by HECO, is undoubtedly simple to implement but would have a higher rate impact than any one of the mechanisms in IRs 3a, b, or c, with no guarantee that it would help achieve the State's energy goals.

The potential downside of these mechanisms includes the following:

1. The difficulty of identifying, tracking, and verifying the costs associated with "system reliability", "customer additions", and "O&M costs associated with complying with Act 155". The effective implementation of these revenue enhancing mechanisms would require the Commission to adopt very specific definitions of the types of costs that can be included in these costs categories, and would require the HECO Companies to develop a clear and transparent recording and reporting mechanism that could be used by the Commission to verify these costs.
2. When a cost is incurred for "system reliability" (or for any of the purposes specified in 3b or 3c) as well as for other reasons (such as for load growth or other purposes unrelated to those specified in the PUC IRs), there would be issues regarding how much of this cost could qualify to be included in the revenue enhancing mechanism.
   For instance, the determination of the "inter-rate case revenue adjustment equal to the difference in operating and maintenance costs associated with Act 155 from those included in base rates" could be particularly problematic as evident in HECO's response to "PUC-IR-52" subpart c. Some HECO activities, such as negotiating purchase power

agreements, may be associated with Act 155 and also associated with the normal business activities of the utility. HECO has performed this activity even before the inception of the statutorily mandated RPS in Act 155. The determination of how much of this activity is allocated and associated with complying with Act 155 and included in the revenue enhancing mechanism, and how much is allocated to the utilities' normal business - will need specific PUC guidance. If there are no clear, transparent, and specific guidelines by the PUC on how and what O&M costs qualify as "associated with complying with Act 155" and are not included in the base rates, it could potentially result in double recovery, or overcompensate the utility for the same costs.

3. The O&M portion of HECO's proposed RAM includes labor and non-labor O&M. Allowing only this portion of HECO's RAM proposal as provided in IR 3d also limits the rate impact on consumers. DBEDT however maintains that allowing the automatic escalation of the labor expense based on the current contractual wage rate increase (as proposed by HECO) would make the utilities indifferent to labor cost increases and eliminate the utilities' incentive to manage their labor costs through their contractual negotiations with the union.

PUC-POST-HEARING-IR-9

Should the RAM concepts described at 3a and b be based on gross or net plant additions?

PUC-POST-HEARING-IR-9-DBEDT-Response:

The RAM concepts described in 3a and 3b should be based on net plant additions (net of depreciation accrual, CIAC, and deferred taxes) consistent with the net plant-in-service component of the utilities' average rate base calculation.

PUC-POST-HEARING-IR-10

Please propose allocation methods among customer classes for each 3a, b, c and d and explain the basis for the allocation.

PUC-POST-HEARING-IR-10-DBEDT-Response:

The revenue enhancing mechanisms provided in IRs 3a, b, c, and d allow the recovery of the increases in specific non-fuel costs such as the return on net plant additions related to system reliability and customer additions, and O&M costs associated with complying with Act 155 that are not recovered in the base rates, or increases in the O&M portion of HECO's proposed RAM. In the HECO Companies' cost-of-service study methodology, these costs are considered "fixed costs" in that they do not vary with the kilowatt-hour sales. They are classified as either customer-related or demand-related costs and are allocated accordingly. The customer-related costs are allocated to the rate classes based on the number of customers. The demand-related costs are allocated based on some measure of the classes' kilowatt (kW) demand such as average kW demand, class peak demand, or the classes' non-coincident demand. The energy-related costs, which only include the fuel and purchased energy costs in HECO's cost-of-service study method, are allocated based on kilowatt-hour sales.

The HECO Companies prepare cost-of-service studies in rate cases for rate design purposes, as well as for use in allocating the requested revenue increase among the rate classes. One of the important results of these studies is the estimate of the classes' rates of return on rate base at present rates, which is a major consideration in allocating the amount of the Company's requested revenue increase. Generally, those rate classes with rates of return on rate base at present rates that are lower than the system rate of return are allocated a higher proportion of the requested amount of revenue increase than those classes with rates of return that are higher than the system rate of return.

DBEDT generally supports allocation of costs based on cost causation or cost responsibility as may be determined in a systematic method such as that used in HECO's cost-of-service study. DBEDT notes however that in HECO's Test Year 2009 Rate Case, Docket No. 2008-0083, the interim rate increase of $61,098,000 that was approved by the PUC and became effective on August 3, 2009, was allocated among the rate classes based on a percentage allocation provided in a settlement agreement between HECO, the Consumer Advocate (CA), and the Department of Defense (DOD). The basis of the agreed upon percentage allocation of the interim increase between these three parties was not provided in the settlement agreement filed with the PUC on May

15, 2009.[37] HECO's proposal for allocating the revenue increase from the RAM portion of its decoupling proposal is based on this settlement agreement percentage allocation of the interim rate increase. This allocation, agreed to by the CA, HECO, and DOD, would allocate 35.74% to the residential class, and 64.26% to the non-residential classes. HECO proposes to combine all the non-residential rate classes into one class for purposes of allocating the RAM revenue adjustments.

While DBEDT does not object to HECO's proposal, DBEDT proposes an alternative method to allocate the inter-rate case revenue adjustments (RAM) provided in the mechanisms in 3a, 3c, and 3d based on the proportion of each rate class' kilowatt-hour sales to the total system sales for the recovery period; and to allocate the revenue adjustments provided in the mechanism in 3b based on the number of new additional customers in each of the rate classes for the recovery period. DBEDT believes that allocating the revenue adjustments from the mechanisms in 3a, 3c, and 3d based on the classes' kilowatt-hour sales is reasonable for the following reasons:

1. The classes' kilowatt-hour (kWh) sales are easily and accurately determined through metered data and are easily verified.

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[37] Docket No. 2008-0083, HECO Test-Year 2009 Rate Case-Stipulated Settlement Letter, Exhibit 1, Page 85. May 15, 2009.

2. Kilowatt-hour sales-based allocation is simple and easy to implement.
3. The utilities' costs associated with system reliability as well as its O&M costs are affected by the customers' kilowatt (kW) and kWh loads. Unlike the kWh sales however, metered kW load data are not available for all rate classes.
4. Allocating the revenue adjustment associated with O&M costs for complying with Act 155 based on kWh sales is reasonable as the Renewable Portfolio Standards mandated in Act 155 is provided in terms of percentage of the utilities' net kWh sales.
5. Allocating the revenue adjustments from 3a, 3c, and 3d based on the classes' kWh sales would provide the appropriate price signal to consumers, i.e., rate classes with decreasing kWh sales will be allocated less of the revenue adjustments relative to the rate classes with increasing kWh sales.

Allocating the revenue adjustments from the mechanism in 3b based on the number of new additional customers in each rate class is reasonable as this mechanism is associated with the plant additions related to customer additions. The Commission must require the utility to provide a clear and transparent method for determining the number of new customers in each rate class, and once specified it is easily determined and verifiable. This allocation base is simple and easy to implement.

PUC-POST-HEARING-IR-11

What should the Commission consider in selecting an ROE to use in calculating revenue enhancements between rate cases associated with rate base changes. Why should the ROE used in calculating the inter-rate case revenue adjustments based on rate base changes be equal to the ROE authorized in the rate case (per the proposed RAM), as the inter-rate case ROE appears to be guaranteed and the rate case ROE is an opportunity to earn the authorized return? Please discuss and quantify.

PUC-POST-HEARING-IR-11-DBEDT-Response:

DBEDT believes that using the authorized ROE in the rate case in calculating revenue enhancements between rate cases associated with rate base changes is reasonable for the following reasons:

1. The authorized ROE has been vetted and determined within the rate case's rigorous process that includes prudent review by the CA, by other parties in a rate case (particularly the DOD), and by the Commission.
2. The inter-rate case recovery of revenue enhancements associated with rate base changes simply allows the utilities more timely recovery of plant investments that have been placed into service, and such timely recovery should not be a basis for using a different ROE from the authorized ROE in the rate case.
3. While it may be argued that decoupling increases revenue stability and reduces the shareholders' risks (all else being equal), the quantification of the effect of decoupling on the Company's ROE is subject to a wide range

of considerations that need to be fully evaluated and litigated in the Company's general rate case filing, where arguments and analysis can be vetted in the context of each utility's (HECO, HELCO, MECO) individual circumstance.

4. The determination of the Company's ROE should take into account not only the impact of the decoupling mechanism that may be approved by the Commission, but also the impact of all other cost recovery mechanisms, such as the existing ECAC and other future mechanisms (such as a purchased power cost recovery adjustment clause and REIS/CEIS). Also to be taken into account is the impact of other initiatives supported in the Energy Agreement that may be approved by the Commission (such as feed-in tariffs and the utilities' renewable energy commitments).

PUC-POST-HEARINGS-IR-12

Please discuss the pros and cons of the Commission approving a RAM that consists of 3a, b and c with and without an RPC compared to the RAM proposed by HECO.

PUC-POST-HEARINGS-IR-12-DBEDT-RESPONSE:

RPC is an alternative form of revenue enhancing mechanism to the RAM portion of HECO's decoupling proposal. It provides revenue increases based on additional customers in the system. Approving a RAM that consists of 3a, b, and c with RPC could potentially result in the utilities recovering the same costs more than once, depending on what data are used to calculate the RPC amount. For instance, the RPC, which is simply the revenues per customer (net of revenues from separate surcharge mechanisms such as ECAC, purchased power cost adjustment, etc.), could include the costs associated with system reliability, revenue increases based on additional customers, or costs for complying with Act 155. A clear and transparent definition and guidelines on what costs qualify for each mechanism is necessary to ensure consumer protection and that there is no double counting or double cost recovery. Furthermore, there must be a clear, transparent, and verifiable method of determining the number of customers for calculating the RPC.

Approving all RAM mechanisms provided in 3a, b, and c with or without RPC may overcompensate the utilities and have significant impact on the ratepayers. As illustrated in HECO's

Response to PUC-IR-52, Revised2, filed on August 14, 2009, a RAM that consists of 3a, b, and c with or without an RPC provides higher estimated return on equity than HECO's O&M RAM proposal.[38] HECO did not provide a similar calculation for HECO's RAM proposal with both O&M and ratebase changes.

[38] Docket No. 2008-0274, HECO's Response to PUC-IR-52, Revised2, August 14, 2009. Att.1 WP, Summary tab. Return on Equity, Lines 5, 10, and 11.

PUC-POST-HEARINGS-IR-13

Please discuss the pros and cons of an ECAC in which (a) the utility bears the risk for heat rate changes within a performance band (e.g., plus/minus 50 Btu from the target) while (b) all changes in costs associated with heat rate changes outside the performance band are passed through to customers.

PUC-POST-HEARINGS-IR-13-DBEDT-Response:

Several parties in the instant docket, including DBEDT, advocated making the ECAC a full cost recovery mechanism and eliminating the efficiency incentive embedded in the ECAC calculation, if a decoupling mechanism is adopted by the Commission. This incentive mechanism in ECAC results from the use of a fixed heat rate or efficiency factor in the ECAC calculation which is set during a rate case. The CA and the HECO Companies claim that this fixed heat rate in the ECAC calculation provides an incentive to the utilities to operate their generating units efficiently.[39] This is achieved by the utilities performing regular and consistent maintenance of their generating units to keep them running efficiently.

The incentive mechanism is structured such that, when a utility's actual heat rate is lower (more efficient) than the fixed heat rate used in the ECAC calculation, the utility is using fewer barrels of oil than is recovered by the fixed heat rate, and the utility is allowed to keep the cost savings.

[39] Docket No. 2008-0274. Joint Final Statement of Position of the HECO Companies and Consumer Advocate, May 11, 2009, Exhibit D, Page 1.

Conversely, if the utility's actual heat rate is higher (less efficient) than the fixed heat rate used in the ECAC calculation, the utility is using more barrels of oil than is recovered by the fixed heat rate, and the utility pays for those additional fuel costs. One party (HDA) claimed that this mechanism impacts the RBA portion of the decoupling mechanism as it effectively results in the utility not being able to separate the total actual revenues received from ECAC, as well as not being able to recover the total actual fuel costs. DBEDT observes however that this claim may be moot as the utilities prepare and file with the Commission a quarterly reconciliation of its actual fuel expense and revenues collected from ECAC.[40] DBEDT is uncertain as to whether the revenues from ECAC that are used in the reconciliation include the fuel savings achieved when the heat rate is lower than the fixed heat rate in the ECAC calculation.

The built-in incentive in the ECAC calculation could provide disincentives for the utilities to integrate/add renewable power generation in the system as the addition of renewable power generation to the system, especially the variable or intermittent renewable generation, could require the utility to run higher amounts of spinning reserve (or regulating

[40] Docket No. 2008-0273. HECO Response to PUC-IR-43. June 22, 2009. Page 2, item 2.

reserve) which is more costly as these units must operate at lower output level where efficiency is lower.[41] Therefore, the fixed heat rate in the ECAC calculation could incentivize the utilities to run their units more efficiently and reduce variable renewable generation in the system (i.e., less renewable energy purchases or increased curtailment of purchased renewable power).

In their Joint Final Statement of Position ("HECO/CA Joint FSOP") filed on May 11, 2009, the HECO Companies and the CA indicated that they would "consider a deadband around the fixed sales heat rates in the ECAC that preserves an effective incentive to operate efficiently, (and) also reduces the disincentive to accommodate increased amounts of renewable energy."[42] HECO and the CA then proposed a ±50 btu/kWh deadband around the fixed heat rate in HECO's ECAC. This deadband means that if HECO's actual heat rate is within the ±50 btu/kWh deadband, that ECAC will operate as a full cost pass-through, so that if the actual heat rate is below the fixed heat rate by an amount up to 50 btu/kWh, then the total fuel cost savings will be passed through to the consumers. If the actual heat rate is higher than the fixed heat rate by up to 50 btu/kWh, the total additional fuel costs will be borne by the consumers.

[41] Docket No. 2008-0274. HECO Response to PUC-IR-53. August 7, 2009, Page 2.
[42] Docket No. 2008-0274. Joint Final Statement of Position of the HECO Companies and CA. May 11, 2009. Exhibit D. Page 2.

On the other hand, the utility will be allowed to keep all the fuel savings or pay for the total fuel cost overage resulting from the differences between the actual and the fixed heat rates outside of the deadband. In other words, if the actual heat rate is lower than the fixed heat rate by more than 50 btu/kWh, the fuel savings from 50 btu/kWh and up will be kept by the utility; and if the actual heat rate is higher than the fixed heat rate by more than 50 btu/kWh, then the resulting additional fuel costs will be borne by the utility.

DBEDT offers the following observations, comments and suggestions:

1. The pros and cons of adopting a deadband such as proposed by the HECO Companies and the CA will depend on the goal of adopting such a mechanism. During the panel hearings, HECO indicated the CA's desire to keeping the fixed heat rate in the ECAC calculation to incentivize the utilities to operate their generating units efficiently. To DBEDT's knowledge there has not been a study or analysis prepared by either the CA or the HECO Companies to demonstrate or verify as to whether or not the CA's goal for keeping this incentives is being achieved. There is no substantive evidence in the record of the instant docket to demonstrate whether or not an ECAC with a deadband is the most effective, reasonable, and efficient mechanism to

incentivize the utilities to operate their generating units efficiently.

2. Since the utilities prepare and file a quarterly reconciliation of the revenues from the ECAC and the total fuel expense, adopting a performance band such as proposed by HECO will require the Commission to provide specific guidelines as to what revenues and fuel expense qualify to be included in such reconciliation. For instance, will the increase in fuel costs or the fuel savings outside of the performance band be included in such reconciliation? Further, if such increase in fuel costs or fuel savings is not included in the quarterly ECAC reconciliation, and if the RBA portion of decoupling is adopted by the Commission, are these amounts allowed to be included in the RBA? And what will be the impact on both the ratepayers and the utility on whether or not these amounts are included in the RBA portion of decoupling?

3. The determination of a reasonable performance band will be difficult, although it may be feasible. Defining and determining what is "reasonable" is a challenge in and of itself. Based on a review of the record in the docket as well as discussions with HECO (in DBEDT's effort to try to understand how the proposed deadbands were derived), there appears to be no substantive analytical support for

determination of the deadband of ±50 btu/kWh for Oahu, Lanai, and Molokai, and for the ±100 btu/kWh for Maui and HELCO proposed by the HECO Companies and the CA. As discussed in Exhibit D of the HECO/CA Joint FSOP and per discussion with HECO, the ±50 btu/kWh deadband for HECO was simply based on the difference between the estimated heat rate of 0.011166 mbtu/kWh from a production simulation run using the test-year sales update of 7,484.7 gWh, and the heat rate of 0.011185 mbtu/kWh based on higher test-year sales of 7,657.8 mWh. The updated sales are lower by 2.3% than the initial test-year sales used in HECO's direct testimony in the 2009 test-year rate case. The heat rate of 0.011166 mbtu/KWh with the lower sales was lower by 19 btu/kWh than the heat rate of 0.011185 mbtu/kWh using the higher sales forecasts. Based on these numbers, HECO and the CA concluded and agreed that if sales decrease or increase by about 5% (approximately double the 2.3% difference in the sales used for the two production runs), then the heat rate will correspondingly decrease or increase by 50 btu/kWh (double the 19 btu/kWh heat rate difference between the two production runs and rounded up to 50). This is the basis of the ±50 btu/kWh deadband proposed by HECO and the CA. The HECO's and CA's conclusion and proposed deadband for HECO implies that decreases in sales will always result in decreases in heat rates, or increases in sales will always result in increases in heat rates. Put another way, decreasing sales make HECO's generation units more efficient, and increasing sales make HECO generation units less efficient. DBEDT observes that this is not a reasonable conclusion as changes in sales are not the only factor affecting the utility's heat rate, and therefore doubts the usefulness of the proposed deadband for HECO.

The flaw in HECO's and the CA's conclusion from such analysis becomes even more apparent with the results of a similar "analysis" used as the basis for the proposed ±100 btu/kWh deadband for Maui. The Maui production simulation run provided opposite results from the HECO production run, resulting in higher heat rate when sales decreased, and lower heat rate with higher sales.

If these deadbands are adopted, it could have different and uncertain impacts on HECO, HELCO, and MECO - and it is highly uncertain whether or not it will achieve the CA's intent to incentivize the utilities to efficiently maintain their generation units.

4. If the intent is to reduce the disincentive for the utilities to accommodate increased amounts of renewable energy as stated in Exhibit D, page 2 of the HECO/CA Joint

FSOP, an ECAC with a performance band will probably help accomplish this intent, depending on how wide or narrow the band is set. HECO's response to PUC-IR-43, Attachment 2, reported the utilities' actual and recovered fuel expense for 2004 to 2008 for HECO, HELCO, and MECO. HELCO's actual fuel expense consistently exceeded the amount that was allowed to be recovered through the ECAC because of the fixed heat rate. MECO's actual fuel expense exceeded the recoverable amount for 3 of the 5-year reporting period. Both HELCO and MECO have higher amounts of variable renewable power generation in the system which may have contributed to the less efficient heat rates (actual heat rates higher than the fixed heat rates) and higher fuel costs. Based on these data, adopting a performance band around the fixed heat rate in the ECAC calculation as proposed by HECO will allow HELCO and MECO to recover the costs overage within the deadband. If the cost overage is due to large amounts of variable renewable generation such as in HELCO's and MECO's system, allowing them to recover the entire cost overage (by making ECAC a full cost recovery mechanism through removal of the fixed heat rate) is more effective in removing the disincentives for the utilities to accommodate increased amounts of renewable power generation.

5. If the intent is to incentivize the utilities to operate their generation units efficiently, the PUC may examine other incentive mechanisms with verifiable and measurable results, rather than a "hidden" incentive mechanism such as the one included in the existing ECAC calculation. If the RBA portion of decoupling is adopted by the Commission, DBEDT believes that a full cost pass-through ECAC mechanism will fully decouple sales from revenues.

PUC-POST-HEARING-IR-14

Please discuss the pros and cons of an ECAC that remained the same as the current ECAC but removed the Btus used for spinning reserve from the heat rate calculation.

PUC-POST-HEARING-IR-14-DBEDT-RESPONSE:

HECO's response to PUC-IR-53, filed on August 7, 2009, discussed the need for spinning reserve for grid stability and service reliability. HECO also discussed the need for higher amounts of spinning reserve (or regulating reserve) as the amount of variable renewable generation is added to the systems, as well as the effect of higher amounts of spinning reserve on the utility's heat rate.

Removing the Btus used for spinning reserve from the heat rate calculation for ECAC will undoubtedly and significantly increase the disincentives for the utilities to accommodate renewable generation to the system. Furthermore, removing the Btus for spinning reserve for the heat rate calculation implies that such Btus are easily determined and verifiable. As HECO discussed in its response to PUC-IR-53, it is not possible to quantify the effects of spinning reserve on the utility's heat rates without accounting for the many other variables that affect the system heat rate.

DATED: Honolulu, Hawaii, August 24, 2009.

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Certificate of Service

I hereby certify that I have served a copy of the Department of Business, Economic Development, and Tourism's Responses to the Commission's Post-Hearing Information Requests in Docket Number 2008-0274, by electronic transmission on the date of signature to each of the parties listed below.

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